Introduction

Section 52 of HB 1, passed during the second extraordinary session of the Kentucky General Assembly, directs the Governor's Office of Energy Policy (GOEP), the University of Kentucky's Center for Applied Energy Research (CAER), the Kentucky Geological Survey (KGS), the Public Service Commission (PSC), and the Environmental and Public Protection Cabinet (EPPC) to produce a report and present recommendations to the Legislative Research Commission regarding carbon management research and technologies in coal-fired power plants. It is important to note that this report is a **snapshot**. This is a dynamic issue and this report is not the definitive answer on the state of legislation or technology. The issue is one that has dramatic implications for Kentucky and requires ongoing monitoring. For example, during preparation of the final draft of this document, the U.S. Senate Environment and Public Works Committee passed *America's Climate Security Act of 2007* out of committee, and the full Senate rejected a House Bill containing among other things stronger CAFÉ Standards as well as Renewable Electricity Standards, both of which were intended to address issues of global climate change, or greenhouse gas emissions.

This report focuses on carbon capture and storage issues related to coal-fired power plants. However, Kentucky has, through its incentives in HB 1, made a commitment to the development of gasification projects producing transportation fuels, synthetic natural gas, chemicals, and fertilizers from coal, coal waste, and biomass. These processes produce carbon dioxide ($CO_{2)}$ that can be more readily captured than that from existing power plants, but nonetheless produce significant amounts. This commitment to these projects increases the need to address carbon management options within the Commonwealth.

Before presenting the response to the questions outlined in HB 1, this report provides a general discussion of climate change legislation and activities outside of Kentucky, how this issue may impact Kentucky, and an overview of technological developments in carbon capture, utilization and storage. A more comprehensive treatment of the answers to the questions in HB1 is included in a full technical report in Appendix A. Other reports referenced in this document are included as appendices to this report. The reports included are but a small sample of the many reports available on this subject, and are not intended to be exhaustive.

Federal, Regional, and State Climate Change Actions

Several climate change bills are circulating in the Congress, with the one gaining the most attention, S.2191, also known as *America's Climate Security Act of 2007* (or the Lieberman-Warner Bill), expected to go to the full Senate in early 2008. This cap and trade bill places limits on emissions of greenhouse gases, with caps beginning in 2012 and becoming more stringent through 2050 (70% reduction from 2005 levels). The bill's target levels for emissions reductions are still being debated and additional amendments are likely. The momentum for action at the federal level, however, is escalating. As mentioned, this bill was passed out of committee on December 5, 2007.

A recently introduced bill addresses the need to rapidly commercialize carbon capture and storage (CCS) technologies. In early November, Sen. John Kerry introduced, S. 2323, which creates a competitive grants program for the construction of three to five commercial-scale sequestration facilities and the construction of three to five coal-fired demonstration facilities with carbon capture. It also establishes an inter-agency panel to develop a regulatory framework for CCS and calls for the U.S. Geological Survey to conduct an assessment of the sequestration capacity in the United States.

For a comparison of the greenhouse gas reduction targets and the assumptions and methodologies of all the climate change bills in the 110th Congress, visit the World Resources Institute (WRI) Web site: http://www.wri.org/usclimatetargets.

Also at the federal level, a recent Supreme Court decision, in Massachusetts v. Environmental Protection Agency, No. 05-1120 (April 2007), ruled that the EPA must take action under the Clean Air Act regarding greenhouse gas (GHG) emissions from motor vehicles, has significant implications for electric generating units and all other stationary sources. The E.P.A. is currently writing rules to comply and is weighing an application by California and 14 other states to set their own emissions standards.

As the United States Congress debates greenhouse gas legislation, many states such as California and Florida are acting on their own or in collaboration with other states in their regions. Some states have imposed limits on GHG, while many have joined carbon dioxide registries, or have formed workgroups to assess potential actions. Twenty states have committed themselves in some way to a regional cap-and-trade program. The Lieberman-Warner bill includes incentives for states to adopt climate policies that are more stringent than the federal program.

At the regional level, there are several cap and trade initiatives: the Regional Greenhouse Gas Initiative among states in the northeast; the Western Regional Climate Action Initiative among 5 western states; and the Midwestern Greenhouse Gas Reduction Accord. There is also a recent initiative among states to establish a uniform greenhouse gas emissions reporting system, which all but 11 states have joined.

Kentucky's Electric Landscape

Kentucky relies on coal-fired power for more than 90 percent of its electricity, and in 2006, this resulted in more than more than 93 million metric tons of carbon dioxide emissions. When discussing legislation mandating reduction of these emissions, it is important to consider that the existing fleet cannot be replaced quickly; substantial modification will also take time and impose costs. With the increasing possibility of carbon constraints in federal legislation and regulation, Kentucky must find ways to utilize its existing resources – fossil fuels, renewables, and energy efficiency -- and develop and deploy new technologies to positively respond to the challenges with the goals of maintaining the Commonwealth's low-cost energy and preserving the Commonwealth's commitment to environmental quality.

In 2005, the Public Service Commission's projected that Kentucky will need an additional 7,000 MW of generating capacity between now and 2025 (*Kentucky's Electric Infrastructure: Present and Future, An Assessment Conducted Pursuant to Executive Order 2005-121*). This growth will be the result of population growth, economic growth in the Commonwealth, and increased electricity use per household. It is important to note that this does not include the retirement of any existing power plants, some of which are operating beyond their expected life.

Regulated utilities serving customers in Kentucky will have to meet the needs of these customers, as is the nature of the regulatory compact, which allows them to serve as a regulated monopoly within the boundaries of their service territory. This "obligation to serve" will mean that the power needs of their customers must be met through market purchases or by the building of new generation.

Historically, Kentucky's citizens have been fortunate to have had some of the lowest electricity rates in the nation. These low rates have not only benefited residents, but they have helped to attract major energy intensive industries that provide high numbers of well-paying jobs throughout the state (aluminum smelters in Western Kentucky, automotive manufacturers in Central Kentucky, steel mills along the Ohio River). Federal legislation, whether it be in the form of a carbon tax or cap and trade program, will make coal fired electricity generation more expensive. Utilities would have to pay the carbon tax or in the case of cap and trade, either make investments to reduce carbon emissions or buy carbon credits. These costs will be passed on to the ratepayer. The economic impact of a carbon-controlled future on the state of Kentucky could be significant. Estimates are that the cost of adding carbon capture and sequestration capability at existing coal-fired facilities will increase electricity costs of between 50% and 300%.

Any legislation that adds costs to coal-fired electricity generation that are not also levied against other forms of generation would raise Kentucky's rates disproportionately compared with states having other resources and would thus lessen the differential in cost of electricity that Kentucky currently enjoys with respect to other states.

One way to reduce the impact of any rate increase would be to increase end-use efficiency in the Commonwealth. This would also help achieve carbon reduction goals. Kentucky has one of the highest per capita electricity consumption rates in the nation. While some of this per capita use of electricity is due to the energy intensive industries located in the state, per capita residential use is also high relative to the rest of the country. A recent report completed for the Governor's Office of Energy Policy states, "Kentucky's electric rate history explains why Kentucky electric customers use more electricity than in the U.S. as a whole, and why until recently there has not been a strong interest in improving energy efficiency. The changing cost situation and broader environmental concerns call for a number of responses." (La Capra and Associates, *Report on Rate Design and Ratemaking Alternatives as They Impact Energy Efficiency*, November 2007, see Appendix H). The La Capra report recommends a broad range of actions to spur end use energy efficiency in all economic sectors. HB1 has directed the

Public Service Commission to examine existing statutes as they relate to energy efficiency and to make recommendations to the General Assembly.

Another method to decrease the carbon dioxide emissions associated with generation of electricity is to increase the percentage of generation capacity that uses renewable resources. Kentucky has limited potential, *given today's technology*, to use renewable resources to meet base-load power needs. According to the U.S. Energy Information Administration (EIA), in 2005 (the most recent data available), renewables (mostly hydroelectric) generated 840 MW, or approximately 4.3% of Kentucky's electricity. There is some potential for growth in the areas of hydroelectric and landfill methane gas, and HB1 provides some incentives for the development of renewable technologies. Kentucky, was one of the first states that signed the 25 x '25 initiative, with a goal to use renewable energy and energy efficiency as a means to get at least 25 percent of our energy from improved technology and renewable resources, such as solar, biomass and biofuels, by the year 2025.

The increased use of energy efficiency and renewable assets will not eliminate the need for base-load generation. What fuel to use for that base-load generation is in some states being answered by a growing interest in nuclear generation; in Kentucky, that is not an option, as it is at this time statutorily prohibited.

In other states, proposed coal fired power plant projects have been abandoned or changed to use natural gas as a fuel source, in order to reduce their carbon intensity. A natural gas combined cycle plant generates approximately half the carbon dioxide per kilowatt hour. Kentucky has a number of natural gas-fired turbines that are used for peak generation of electricity. To use more natural gas in electricity generation would require construction of large base-load units to replace the current fleet of coal-fired generators. The costs of the new construction and the cost of base-load generation would be prohibitive. In addition to the capital costs, the fuel costs of natural gas are higher and more volatile than coal. The United States is becoming increasingly dependent upon imported natural gas, and this would exacerbate the energy security issues associated with importing energy resources. This increasing demand for natural gas for electricity generation will lead to higher prices for home heating and for industrial markets. For these reasons, natural gas is not expected to meet much of the future needs of base-load generation.

Because of its low cost and abundance, coal will continue to provide much of the Commonwealth's base-load electricity. According to many government, academic, and industry figures (among these, the Massachusetts Institute of Technology, World Resources Institute, Electric Power Research Institute, Energy Information Administration, Congressional Office of Management and Budget) coal will also continue to supply the country with base-load generation for many years.

Technology Solutions

Even taking into account anticipated future greenhouse gas emissions limits; expectations are that the country will continue to use coal as a fuel for electricity generation. In the past, the utility industry has met its growing need for electric generation and has dramatically reduced total emissions of sulfur dioxide, nitrous oxides, and mercury while increasing the amount of electricity generated from coal fired power plants. In the same way, efficiency improvements and technology developments can enable the industry to continue to utilize coal while reducing emissions of carbon dioxide. The improvements and technology development are already underway. For these to be successful in meeting demands for substantial carbon dioxide emissions reductions, public policymakers must commit a level of financial support for research and development sufficient to scale up the size of the demonstration projects currently under development and to do so in a much shorter time frame than is now planned, and with an eye toward the deadlines in the relevant federal bills under consideration.

There are five major technological paths to carbon dioxide reduction in coal fired power plants: (a) co-firing existing power plants with biomass and coal; (b) improving the efficiency of existing power plants; (c) installing new and more efficient generation technologies; (d) installing carbon separation and capture technologies; and (e) sequestering the captured carbon dioxide. Co-firing wastes or biomass can have significant and immediate CO_2 reduction impact due to replacing a substantial portion of coal (up to 15 percent by weight appears technically feasible if resources are available) with carbon neutral biomass. Improving efficiency at existing plants by operational or maintenance modification can yield reductions in CO_2, of 10%-16% in a unit, and overall fleet improvement of 3%-5% (CURC). New, more efficient technologies include units that produce steam at extremely high temperatures and pressures (ultra-supercritical pulverized coal, or USCPC) and integrated gasification of coal and combined cycle generation (IGCC).

Currently, new supercritical and ultra-supercritical power plants are producing approximately 10%-18% less carbon dioxide emissions than a conventional pulverized coal (PC) power plant. CURC/EPRI estimate that by 2025, the greater efficiencies of supercritical and ultra-supercritical power plants could result in 35 percent fewer emissions than those from the same size conventional power plant. Installing supercritical and ultra-supercritical boilers on existing plants would be very costly; however, the cost of a new super- or ultra-supercritical plant is not much greater than the cost of a conventional plant, and with continual improvements, the cost differential will be reduced (CURC/EPRI).

IGCC plants combine considerably greater efficiency with much improved control of CO_2 and also sulfur dioxide, nitrous oxides, and mercury. Because of higher construction and operating costs, the cost of electricity from an IGCC plant may be as much as 35 percent higher than from a conventional PC power plant. However, as multiple IGCC plants are deployed, operated, and improved, this differential is expected to decrease greatly.

There are technologies in development that can be used on existing power plants or built into the design of new power plants that remove CO_2 from flue gases (post-combustion). These technologies are being modeled on currently utilized industrial processes for producing pure carbon dioxide for commercial and industrial applications. These offer high CO_2 removal in the near to mid term, but they presently impose high costs for installation and can require up to one-third of the electricity generated by the power plant just for operating the chemical removal equipment. There are technologies in development that show promise at reduced cost, but they have not been demonstrated at large scale. Other technologies such as the new techniques of firing coal in oxygen rather than air (oxy-combustion) can produce near pure streams of CO_2 for capture and utilization or sequestration. These processes also currently are very costly in both equipment costs and parasitic drains on the electricity generated by the power plant largely for operation of air separation units needed for production of oxygen. IGCC offers efficient capture of CO_2 and at operating costs that are quite manageable, once the capital cost of the power plant is met.

Carbon reduction, separation and capture are only part of the equation. If carbon dioxide is produced and is not to be released into the atmosphere, it must be stored. Enhanced oil recovery (EOR), enhanced coal bed methane recovery (ECBM), and enhanced gas recovery (EGR) all will play a part in the storage of captured CO_2. For example, in the Weyburn Oil Fields in Canada, CO_2 is carried in a pipeline captured from the North Dakota Gasification Plant and is used to increase the production of the field. It is predicted that the CO_2 EOR operation will enable an additional 130 million barrels of oil to be produced, extending the field's commercial life by approximately 25 years. It is anticipated that about 20 million tons of CO_2 will be injected and become permanently stored 1,400 m (4,600 ft) underground over the 25 year lifetime of this project. Increases in this use of carbon dioxide will depend largely on the development of large-scale pipeline systems for delivering CO_2 to the points of need.

EOR, ECBM, and EGR have potential in Kentucky; however, it is unclear how much storage capacity is available. This is an area that HB1 provided funding for further research. There are some other uses for $CO_{2,}$ such as those in the food, drug, and chemical industries. It is unlikely that these uses will utilize the volume of CO_2 needed to be captured. For example, the amount of CO_2 produced by electricity production in the United States in 2006 was over 2.4 billion metric tons, according to the Energy Information Administration (EIA). (Compare this to the 20 million tons to be stored in the Canadian EOR project over the 25 year lifespan of the project.)

It is important to determine what the capacities for these beneficial uses for CO_2 are in Kentucky, so that the cost of removal, transport and injection can be offset by revenue. However, because of the volume needed to be stored, permanent storage or sequestration in geologic formations is the only viable option at this point for removing large volumes of CO_2 from the atmosphere.

The KGS has found that the subsurface geology of Kentucky is generally favorable for carbon sequestration and enhanced oil and gas recovery. The U.S. DOE *Carbon Sequestration Atlas of the United States and Canada* estimated in 2007 that over 3,500 billion tons of CO_2 sequestration potential exists in the United States and Canada. The U.S. DOE has begun a three-phase research program that includes assessment and validation of potential and large-scale demonstration of sequestration. The KGS is participating in three of the regional sequestration partnerships. Numerous legal issues relating to CO_2 ownership and liabilities are being addressed by several government and academic entities. The MIT study, *The Future of Coal*, concluded that “there do not appear to be unresolvable open technical issues underlying these questions…” and that “the hurdles to answering these technical questions well appear manageable and surmountable.”

The Battelle Global Energy Technology Strategy Program in 2006 reported that “assuming that other advanced technologies are developed and deployed along with carbon capture and storage systems, this potential storage capacity should be more than enough to address CO_2 storage for at least this century.”

The geology of Kentucky seems suited for long term storage or sequestration, but deep wells have not been drilled and original data has not been gathered at depths to know definitively. The Kentucky Geological Survey along with private partners is interested in forming a public/private partnership, along with the Commonwealth, which allocated $5 million in HB1, to collect original data to better assess the capacity of the geology for sequestration.

Recommendations

The pace of the research and development may not be sufficient to meet the challenges especially to the electricity sector in Kentucky. As a result of the research conducted to respond to the thirteen questions outlined in HB1, we respectfully offer the following options recommendations to the General Assembly to consider when looking at this important issue going forward:

- Provide incentives or grants for large scale public/private partnerships between the Commonwealth, utilities, Kentucky’s research institutions, and carbon capture technology providers to site large scale carbon capture technology research and demonstration projects in the Commonwealth.

- Encourage through additional funding, the further development of large scale carbon dioxide storage demonstration projects, including EOR, EGR, ECBM, storage in deep unmineable coal seams, and geological sequestration.

- Develop mechanisms whereby the Commonwealth can provide some liability protection for the demonstration projects for carbon capture and storage, to encourage participation of private entities in public/private partnerships.

- Provide funds for public education/outreach programs to educate the public on carbon sequestration.

- Provide the Public Service Commission with tools necessary to encourage utilities to develop and adopt new technologies that can reduce or capture carbon dioxide. This could include incentives and/or cost recovery for the early adoption of new generation technologies, cost recovery for renewable energy development, and cost recovery mechanisms for research and development programs.

- Provide the Public Service Commission with tools necessary to encourage utilities to develop and adopt new policies that can support reduction or capture of carbon dioxide. This could include changes in rate design or changes in demand side management programs in order to promote increased energy efficiency.

- Determine appropriate incentives or necessary statutory changes to encourage adoption of energy efficient products and practices by consumers and to implement the recommendations of the November 2007, *Report on Rate Design and Ratemaking Alternatives as They Impact Energy Efficiency*.

- Alter economic development tools presently in existence to specifically help energy-intensive industries make adjustments to remain viable in a higher rate environment.

- Establish an informal Carbon Dioxide Working Group consisting of energy leaders in the legislature, the executive branch, research universities, industry, and environmental groups in order to keep abreast of the ever changing legislative environment and technology development.

- Encourage the federal delegation to increase funding in research and development of carbon capture technologies and carbon sequestration.

- Encourage the federal delegation to work to ensure that if regulations on carbon are put in place that they be no more stringent than those for natural gas combined cycle power plants. This decrease in the required percentage removal from a coal facility could result in a decreased cost of removal of carbon dioxide from these facilities, as the cost of many of the processes increase exponentially as a higher percentage of carbon is removed. This would ensure a more level playing field.

- Work with the federal delegation to attempt to influence the federal legislation in such a way as to dampen the rate shock to Kentucky ratepayers.

Summary of Responses to Questions

1. The current status of research and technology to manage carbon dioxide in existing coal-fired power plants.

Many technologies for managing carbon in existing power plants are being developed and improved continually. However, except for the most inexpensive techniques for increasing plant efficiency through operational and maintenance improvements, the technologies are costly to install and operate and often greatly decrease the marketable electricity output of a generating unit. Nonetheless, progress is being made, and plans are being advanced for substantially reducing carbon dioxide emissions at relatively low cost and with manageable electricity penalty within two decades. CURC, MIT and others argue that all technologies should be developed, including fuel switching, modification of existing plants, and development of advanced technologies for new plant. This will require a very strong and continuing federal commitment. Currently, federal funding for research and demonstration of technologies for capturing carbon dioxide is grossly inadequate.

There are three basic methods available to manage carbon dioxide in existing coal-fired power plants: (1) Replace some percentage of coal with a more carbon neutral fuel to reduce a plant's "carbon footprint;" (2) Increase power plant efficiency; and (3) Capture the released carbon dioxide.

Switching some percentage of the gross heat input to the boiler from coal to biomass effectively reduces the amount of net carbon dioxide emitted to the atmosphere. This results in a net decrease of carbon dioxide emissions per measure of electricity produced. Biomass blending is a relatively inexpensive (material handling/processing equipment; possible burner changing/tuning), easy (simple, proven technology), and quick way to help meet potential carbon reduction goals. There is considerable experience world-wide with biomass blending of many types at a variety of facilities, with mixed but generally good results. There is uncertainty, though, as to how compatible a particular boiler will be with a particular fuel. A more significant potential risk is that according to current EPA rules, fuel switching may trigger New Source Review (NSR) requirements which could require that Best Available Control Technology (BACT) be installed on the basic power plant. That could raise costs at a particular facility considerably. Biomass co-firing coupled with capture and storage of carbon dioxide could dramatically reduce a coal-fired power plant's carbon footprint.

The second method is to increase the thermal efficiency of the power plant. The efficiency of PC boilers has been increased greatly through construction technologies that allow the boilers to produce steam at very high (supercritical) or ultra-high (ultra supercritical) temperatures and pressures. A new supercritical unit compared to a relatively new subcritical unit would see a 10 percent decrease in the amount of CO_2 emitted for the same power production. There is potential for ultra supercritical and IGCC units to have even better efficiencies. Assuming an existing plant efficiency of

35%, a 1% efficiency improvement at a 500 MW unit could result in 4.5 million fewer tons of carbon dioxide emitted over a 40 year plant lifetime.

Some increase in most (especially older) plants' efficiency would be relatively easy, cheap, and quick, though both cost and effectiveness will vary widely from facility to facility. The more complex options for increasing efficiency such as upgrading the operating temperature and pressure of the boiler and/or adding a gas turbine to the power plant would entail much greater costs and take much longer, though they would result in substantial efficiency gains. Having additional power available for sale without the necessity of building new plants is a big plus. Incentives involving rate setting and cost recovery are also cash non-intensive. Possible federal (EPA) regulatory impediments MUST be removed to gain maximum effect. Assuming that an average of a 5% thermal efficiency increase is achieved throughout the fleet, it would mean that the same number of MWh of electricity will be generated with a 10% reduction in CO_2 emissions.

The third method, capturing released carbon dioxide from the combustion gases, requires processes such as chemical solvents, physical absorption, membrane systems, or other methods that are in different stages of development or testing. Of these, **chemical solvent methods** are the only ones approaching power plant scale demonstration and deployment. The primary impediment to capturing carbon dioxide in existing coal-fired power plants is the huge volume of combustion gases, containing (typically) 12-15% CO_2 by volume, that are generated when coal is combusted in air. It is difficult and costly to separate and capture the dilute carbon dioxide from the rest of the combustion gases.

Analysis conducted at the National Energy Technology Laboratory (NETL) predicts that CO_2 capture and compression using amines [e.g., monoethanol amine (MEA) extraction] will raise the cost of electricity from a newly-built supercritical PC power plant by 84%. Costs at an existing supercritical or sub-critical plant will be higher due to the difficulty of adding equipment to units not designed from the start for such technologies. In addition to the costs of capital equipment and the solvent itself, the MEA process is expected to demand about 20%-30% of the generated gross power output to operate the system.

Another approach to capturing CO_2 involves removing the oxygen from air and then burning the fuel in that oxygen mixed with recycled flue gas or water (which is then condensed from the exhaust stream) to produce a much more highly concentrated stream of CO_2. This process, called oxy-fuel combustion, results in a concentration of 80+% CO_2 in the exhaust, with a much lower volume of flue gases (approximately 70% less). This greatly reduces the cost and difficulty of capturing the CO_2 released from the boiler. The biggest costs of oxy-fuel combustion are the stand-alone air separation unit (ASU) required to produce the oxygen and further flue gas purification to bring CO_2 content to the same level (90+%) obtained from post-combustion CO_2 capture processes. In addition to the cost of the ASU itself, approximately 20% -30% of the gross power generated by the power plant is consumed by the ASU to produce the oxygen.

2. Existing sources of support for research related to managing carbon dioxide in existing coal-fired power plant and the adequacy of such sources

There are countless groups in the United States and around the world that are involved in research on carbon capture and sequestration, both from existing and new power plants. These sources can be divided into four basic groups: Government, academic, private research groups, and private industry.

In the United States, the best known government organization is the U.S. Department of Energy (DOE). Through the National Energy Technology Laboratory (NETL), DOE provides funds and is a partner to various other entities engaged in research, development, and deployment of carbon capture and storage projects. In 2003, the DOE formed seven Regional Carbon Sequestration Partnerships (RCSPs) to look at the implementation of carbon sequestration in the United States on a broad scale and lead a national effort to develop the infrastructure and knowledge base needed to commercialize carbon sequestration technologies.

Individual states also have government organizations which actively support research in carbon management, such as the Ohio Coal Development Office, the Kentucky Geological Survey (KGS), and the Kentucky Governor's Office of Energy Policy. KGS is currently doing carbon sequestration research that is primarily focused on geologic storage options in Kentucky. Their work applies to managing carbon at both existing coal-fired power plants and future coal gasification projects. KGS is currently funded for work in three of DOE/NETL's regional carbon sequestration partnerships: (1) Midwest Regional Carbon Sequestration Partnership (eastern and central Kentucky); (2) Midwest Geologic Sequestration Consortium (western Kentucky); and (3) Southeast Regional Carbon Sequestration Partnership (eastern Kentucky coals). In addition, KGS receives funding from the Kentucky Governor's Office of Energy Policy for regional sequestration and CO_2 enhanced oil recovery evaluation. The DOE regional carbon sequestration partnership work in Kentucky has primarily involved evaluation and mapping of existing data. Only one demonstration project involving the drilling of a well and new data collection is planned in Kentucky (in Boone County).

House Bill 1 passed during the 2007 special session will provide KGS funding to obtain much needed geologic data in both the eastern and western Kentucky coal fields, where future coal gasification projects are likely to be built. These parts of Kentucky have not been chosen for demonstration projects in the DOE sequestration partnerships, and through the HB1 funding, Kentucky will be able to better evaluate the location and size of geologic sequestration targets.

The second group spearheading and facilitating research in carbon management is academia. Many universities that have an emphasis on scientific and/or engineering curricula also have energy research centers and/or conduct research on carbon management projects. Purdue University's Energy Center, MIT's Laboratory for Energy and the Environment, and the University of Kentucky's Center for Applied Energy

Research are typical examples. Additionally, many universities such as the University of Texas at Austin are engaged in research projects on specific aspects of carbon capture and control.

Companies that are involved in one or more aspects of power generation are also working to reduce the carbon footprint of coal-fired power generation. American Electric Power (AEP), Duke Energy, E.ON, Foster Wheeler, Babcock and Wilcox, Alstom, Air Liquide, Praxair, Mitsubishi Heavy Industries, and Air Products are just some of the multitude of private companies working in this area.

According to many industry sources, the current research budget for DOE is not sufficient to provide the funding to achieve carbon management needs. If technology is to be the centerpiece for addressing concerns about climate change, then adequate funding and focus is urgently required and sufficient time to develop innovative CO_2 capture technologies is needed. For example, CURC estimates that a long-term research, development, and deployment effort to reduce CO_2 emissions significantly through carbon capture and sequestration would run through 2025 and cost $18 billion.

Several private consortia and private advocacy groups are facilitating or conducting CCS research. Among these are the Electric Power Research Institute (EPRI), the Southern Research Institute (SRI), RTI International, the Western Research Institute (WRI), and the Coal Utilization Research Council (CURC). These groups work with industry and academia to identify and fund promising research projects for carbon capture and removal.

In establishing a research alliance called the "Kentucky Consortium for Advanced Power Generation," CAER pledged $1 million annually in state funds (it is envisioned that these moneys will be supplied as part of a recurring funding line for CAER as described in HB 1) to match funding the CAER will receive from the utilities and other private sector partners. However, a capital investment of $4 million will be required, along with the funding provided by the various utilities in the consortium, to cover the capital cost of the project.

3. The estimated capital and energy costs associated with installing the technology or upgrading existing coal-fired power plants to better manage carbon

As stated, achieving the goal of better carbon management at existing PC power plants can be done in three ways. Arguably the lowest cost technique would be to fire a certain percentage of renewable (near carbon neutral) biomass with coal to reduce a plant's net carbon emissions. There are some costs involved with upgrading existing equipment, such as storage, pulverizers and fuel mixing, but these would be relatively small compared to other options.

The second method is to increase the thermal efficiency of the power plant. Newer units generally have greater thermal efficiency and reduced CO_2 emissions per MWh of electricity produced. This is shown by the lower ratio of BTUs per MW. A new supercritical unit compared to a relatively new subcritical unit would see a 10% decrease in the amount of CO_2 emitted for the same power production. There is potential for ultra supercritical and IGCC units to have even better efficiencies.

Thermal efficiency can be increased at existing coal-fired power plants by retrofitting the sub-critical plants to supercritical or ultra-supercritical performance, or by making a combined cycle plant by adding a gas turbine to the basic steam turbine. Both of these methods would increase the thermal efficiency from approximately 35% to 45-50%, resulting in a decrease in carbon emissions of 20-30%. Unfortunately, converting a sub-critical plant to supercritical or ultra-supercritical performance would require essentially a complete rebuild of the plant, which is economically unfeasible. Adding the complete gas turbine package to an existing plant would cost hundreds of millions of dollars, but would have the advantage of actually increasing net power output instead of decreasing it because of parasitic load.

The third method is to capture and control carbon emissions from the flue gases. For new fossil power plants, the DOE/NETL issued a technical report, *Cost and Performance Baseline for Fossil Energy Plants*.

According to this DOE report for new power plants using bituminous coal, the impact of the addition of commercial 90% carbon capture technology is as follows:

Generation Technology	Increase in Capital Cost based on $/kW	Energy Efficiency Loss, based on HHV
NGCC	112%	14%
PC (subcritical)	87%	32%
PC (supercritical)	82%	30%
IGCC	36%	19%

The **impact on existing units** would be higher due to the nature of adding equipment to units not designed from the start for such technologies. All but two of the PC power plants currently in Kentucky are sub-critical; there are two existing supercritical units and a third in construction. At this time, the costs of retrofitting existing sources with carbon capture technologies are highly speculative. Estimates are that the cost of adding carbon capture and sequestration capability at existing coal-fired facilities will increase electricity costs of between 50% and 300%.

Estimates from studies done by the MIT, NETL, and others show the cost of capture and compression, not including disposal, of CO_2 at existing sub-critical/supercritical PC boilers would increase electricity costs somewhere between 69% and 100%. The variations in these predicted increases are because capital costs for the equipment to capture and compress 90% of the carbon dioxide emissions from an existing power plant will vary radically between facilities due to site specific layout and technological considerations. An additional cost is the energy required to capture and compress the CO2; this cost is estimated to be around 30% of the net output of a typical PC boiler. The final (and again highly variable) cost component of carbon management is the disposal of the carbon dioxide. This will depend on whether or not there is a commercial use available, the distance between the existing plant and the storage/use site, and the (at this time unknown) cost of required infrastructure to move the carbon dioxide from the plant to its final destination.

Efforts are being made to reduce the uncertainty of carbon dioxide transport and storage costs. Compared to storage costs, transport costs are much more easily determined. CO_2 pipelines have been built in many parts of the country, and the technology is established and readily available. CO_2 pipelines operate at higher pressures than natural gas pipelines (2,500-2,700 psi), but are similar to liquefied petroleum gas (LPG) pipelines. Pipeline construction costs will vary with diameter (flow rate) and distance.

4. Identification of specific potential research projects and demonstration projects to enhance the development and deployment of new technology in this area

CAER is requesting funding to expand applied research projects that focus on three approaches for reducing carbon dioxide and other emissions from fossil-fuel power plants:

- Concentration and capture of CO_2 released by coal-fired power plants. The funds requested will be used to (a) modify an existing CAER pilot-plant combustion facility into a versatile CO_2 capture research platform, (b) construct and incorporate a scaled-up, slip-stream version of the platform into the flue gas stream at a selected PC power plant. This objective represents a critical step in developing and demonstrating practical technologies for reducing CO_2 emissions from Kentucky's existing fleet of coal-fired power plants; (c) expand the capability of the ongoing algae bio-fixation study;
- Increase power plant efficiency. This effort will not only increase the amount of electricity produced from each ton of fuel but would do so while simultaneously reducing the amount of emissions per unit of power generated;
- Reduce the overall carbon footprint of the power plant by increasing the use of renewable biomass and agricultural waste resources via production of liquid, gaseous, and solid fuels.

The KGS received $5 million in funding from HB1 (2007 special legislative session) to drill research wells to characterize CO_2 EOR, EGR, and deep permanent sequestration. Over the next 3 years, these KGS projects will provide much needed hard data to characterize the available sequestration options in Kentucky.

One new KGS research project is named "Evaluation of Geologic CO_2 Sequestration Potential and CO_2 Enhanced Oil Recovery in Kentucky." This study is funded by the Kentucky Governor's Office of Energy Policy. The goals of this project are (1) to evaluate the potential for using CO_2 in EOR in major oil fields in Kentucky, and (2) to conduct a regional evaluation of geologic sequestration potential within the Commonwealth. This research will provide a better idea of the quantity of CO_2 that could be utilized in EOR, and the areas and specific targets where geologic sequestration is possible.

Over the last 4 years, KGS has participated in research efforts in the three U.S. DOE carbon sequestration regional partnerships that include Kentucky. These are the Midwest Geologic Sequestration Partnership (MGSC), the Midwest Regional Carbon Sequestration Partnership (MRCSP), and the Southeast Regional Carbon Sequestration Partnership (SECARB).

5. Identification of the types of incentives or other government assistance that would be helpful in supporting the development and implementation of new technologies to reduce carbon emissions at existing coal-fired power plants, including strategies for isolation, capture, and management of carbon dioxide.

A program of taxes or incentives (or a combination of both) to maximize electricity production with minimum CO_2 emissions would encourage carbon footprint reduction.

In the 2007 special session, the Kentucky legislature passed House Bill 1, which included funding for sequestration research at the Kentucky Geological Survey. While this funding is essential to help establish Kentucky's CO_2 sequestration potential, the bill did not provide incentives that will facilitate commercial implementation of carbon capture and storage (CCS) technology. Such incentives will likely be needed for successful development of this technology.

There are currently thirteen facilities in Kentucky that generated 91 million tons of CO_2 in 2006. Sequestering that amount of material will be a complex and expensive task. Unresolved liability risks related to the transportation, injection and storage of enormous quantities of CO_2 in geologic formations is a significant barrier to mobilizing the necessary capital for the needed R&D. Any protection that minimizes or spreads the risk from such litigation would reduce the potential cost and increase the likelihood that projects of this type would be attempted in Kentucky.

Several states have been active in drafting and enacting legislation to provide incentives for clean coal technology development. Most of these initiatives deal with cost recovery, financial assistance, tax credits, and regulatory changes pertaining to coal gasification and coal-to-liquid development. Few of these initiatives deal directly with carbon management or sequestration issues

Two good examples of the types of incentives that will be required to enable large-scale CCS technology can be found in recently passed bills in Illinois and Texas, both of which are pursuing the federally funded FutureGen zero-emission coal generation project. These bills have addressed three major carbon management issues:

- Post-injection ownership and liability for subsurface carbon dioxide
- Tax incentives for use of man-made CO_2 in EOR projects
- Permitting and regulatory streamlining

Additional issues that many feel will require future statutory or regulatory clarification include:

- Ownership of subsurface pore space (storage space for CO_2)
- Agency responsible for regulation of geologic CO_2 sequestration
- Responsibility for long-term monitoring, measurement, and verification of injected CO_2

6. The current status of research and technology in the capture and sequestration of carbon dioxide

Existing capture technologies are not cost-effective when considered in the context of sequestering CO_2 from existing coal-fired power plants. CO_2 is currently recovered from combustion exhaust by using amine absorbers and cryogenic coolers. The estimated cost of CO_2 capture using current technology is estimated to be as high as $150 per ton of carbon – much too high for carbon emissions reduction applications. Therefore the U.S. DOE is pursuing evolutionary improvements in existing CO_2 capture systems and also exploring revolutionary new capture and sequestration concepts.

Opportunities for significant cost reductions exist since very little R&D has been devoted to CO_2 capture and separation technologies. Several innovative schemes have been proposed that could significantly reduce CO_2 capture costs compared to conventional processes. "One box" concepts that combine CO_2 capture with reduction of criteria pollutant emissions are being explored as well.

Examples of ongoing research in carbon capture include:

- new materials (e.g., physical and chemical absorbents, carbon fiber molecular sieves, polymeric membranes);
- micro-channel processing units with rapid kinetics;
- CO_2 hydrate formation and separation processes;
- oxygen-enhanced combustion approaches;
- Development of retrofit CO_2 reduction and capture options for existing large point sources of CO_2 emissions such as electricity generation units, petroleum refineries, and cement and lime production facilities;
- Integration of CO_2 capture with advanced power cycles and technologies and with environmental control technologies for criteria pollutants.

The other main area of research is in carbon sequestration (storage). Efforts to store CO_2 are focused on two categories of repositories: Geologic formations and terrestrial ecosystems. Geologic formations considered for CO_2 storage are layers of porous rock deep underground that are “capped” by a layer or multiple layers of non-porous rock above them. Sequestration practitioners drill a well down into the porous rock and inject pressurized CO_2 into it. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow until it encounters a barrier of non-porous rock (cap rock), which can trap the CO_2 and prevent further upward migration.

The degree to which a specific underground formation is amenable to CO_2 storage can be difficult to discern. Research is aimed at developing the ability to characterize a formation before CO_2-injection to be able to predict its CO_2 storage capacity. Another area of research is the development of CO_2 injection techniques that achieve broad dispersion of CO_2 throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock.

NETL research is focused on three priority types of geologic formations in which CO_2 can be stored: Depleted oil and gas reservoirs; unmineable coal seams; and saline formations. Each presents different opportunities and challenges. Other promising potential avenues for carbon sequestration include injection into basalt and organic rich shales, terrestrial sinks (trees, marginal cropland, wetlands), and ocean injection.

The current status of research and technology of geologic carbon sequestration is, in many respects, in its infancy. While the oil and gas industry has more than 30 years experience injecting CO_2 into oil reservoirs to enhance production, very little has been done with the express purpose of sequestering CO_2 in geologic formations on a commercial scale.

U.S. DOE's Carbon Sequestration Regional Partnerships exist to demonstrate the viability of large-scale capture, transportation, and storage of CO_2 in an economic, safe, and permanent manner. There will be dozens of small scale injection projects (<100,000 tons CO_2), likely followed by larger applications (>1Mtpy CO_2). They are planning to supplement the 25 ongoing geologic injection field tests (1,000 to 10,500 tons of CO_2) across the country with large-volume injections (in the order of 1 Mt per year) of CO_2 in the 2008-2017 timeframe.

7. Identification of marketing opportunities and uses for carbon dioxide as a value-added commodity, the maturity and long-term feasibility of those markets, the potential for carbon utilization relative to the anticipated generation of carbon, and the economic and environmental risks associated with these uses of carbon dioxide

There are numerous current industrial uses for carbon dioxide. The largest uses of CO_2 are:

- CO_2 is used in the metals industry in manufacturing casting molds.
- In MIG/MAG welding; the gas protects a weld from oxidation as it is being made.
- Large quantities are used as a raw material in chemically manufacturing products such as methanol and urea.

- Crushed dry ice is used in "sandblasting" operations to remove surface coatings and tumbling operations to remove "flash" from rubber parts.
- In the food industry, liquid CO_2 is used to decaffeinate coffee (it is a good solvent for many organic compounds). Gaseous CO_2 is used to carbonate drinks, displace air during canning, and prevent fungal and bacterial growth.
- Carbon dioxide is used as an additive to oxygen for medical use as a respiration stimulant.
- As a propellant in aerosol cans, CO_2 replaces more environmentally troublesome alternatives. It can also be used to enhance production in greenhouses, and to neutralize alkaline water.

Unfortunately, the above uses do not result in CO_2 being stored; in all of these applications, the CO_2 is quickly released back into the atmosphere.

The only current commercial use for CO_2 that could result in large volumes being stored is the use of carbon dioxide for EOR in older oil fields and enhanced methane production from unmineable coal seams. According to estimates by the Regional Carbon Sequestration Partnerships more than 82.4 billion metric tons of sequestration potential exists in mature oil and gas reservoirs, and over 180 billion metric tons of sequestration potential exists in unmineable coal seams. This represents over 43 years of storage at the United States' current CO_2 emission rate of approximately six billion metric tons per year. One advantage of this use is that any oil and gas recovered would net against the expense of capturing, compressing, transporting, and injecting the carbon dioxide. The Department of Energy estimates that from 89 billion (short term) to 430 billion (longer term) barrels of oil could be recovered by injecting depleted fields with CO_2.

8. Identification of other uses for carbon dioxide and the feasibility of large-scale implementation of such uses

Some of the potential or proposed commercial uses for CO_2 include enhanced algae growth, conversion to a combustible fuel, and *terra preta*.

Enhancing algae growth uses an enriched stream of carbon dioxide from a power plant. The enhanced growth is accomplished by exposing nutrient-rich algal ponds to sunlight and CO_2 with the algae subsequently used to produce liquid fuels or power. Processes for direct conversion of carbon dioxide into combustible fuels (methane and carbon monoxide) are being researched. These include processes utilizing sunlight and microbial conversion. So far they are preliminary studies and will need substantial further research.

Terra Preta is a potential option for carbon sequestration combined with enhanced biomass production. The approach entails charring of biomass by gasification to produce gaseous fuels, followed by burial of the char for long-term enhancement of soil. This avenue could conceivably be used to significantly enhance the fertility and biomass production rate on, for example, abandoned strip mine lands or other marginal soils that are prevalent in Kentucky.

9. Identification of feasible methods for capturing and transporting carbon dioxide from the generation point to end users, including the construction of carbon dioxide pipelines, rail transportation, or other means, and the positives and negatives for each method

When geologic sequestration sites do not occur immediately below CO_2 sources, CO_2 will have to be transported offsite. Viable options for transport of CO_2 include truck, rail, and pipeline.

The most commonly employed technique for transporting large quantities of CO_2 is by underground pipeline. CO_2 pipelines have been in use since the 1970s to transport CO_2 from natural reservoirs to west Texas for use in EOR. CO_2 pipelines operate at high pressures, where the CO_2 is in a liquid phase. All CO_2 pipelines in current use are made of conventional steel. If the CO_2 is kept free of water, corrosion is not a big problem. Water mixed with the CO_2 can cause serious corrosion problems with normal carbon steel pipe.

CO_2 pipelines have proven to be very safe to operate. They are classified as high volatile/low hazard/low risk per federal regulations. CO_2 does not burn, which eliminates explosion hazards. Ruptures and leaks could occur, and CO_2 could be hazardous if it collects in confined areas, displacing oxygen. But in the 10-year period from 1991 to 2001 there were no CO_2 pipeline-related injuries or deaths in the U.S.

Because of the huge amount of CO_2 and the distances involved, whether or not the CO_2 captured from coal-fired power plants is delivered to an end user or delivered to a location for sequestration the only viable method of transporting CO_2 will be through pipelines. While new facilities which emit large amounts of CO_2 can probably be located near end users or sequestration sites, existing power plants are often located at great distances from them. Large-scale CCS will require a network of pipelines at least equal to the existing interstate natural gas pipeline grid. To establish such a network of pipelines, numerous issues will have to be addressed regarding the siting, permitting, construction and operation of these pipelines.

10. Identification of any issues or concerns relating to carbon dioxide that are unique to Kentucky

The economic impact of a carbon-controlled future on the state of Kentucky, which relies on coal for more than 90% of its electricity, could be significant because other resource options are limited. Kentucky does not have sufficient hydro, wind or solar resources to replace coal-fired baseload generation, given the state of today’s technology. Natural gas prices are more volatile than coal prices and they are projected to escalate as more natural gas-fired generation is constructed elsewhere in the country. Higher energy prices coupled with the loss of coal-related jobs could have a serious impact on our state's economy. Nuclear power is not a statutory option at this time. If it were an option to consider, the capital construction costs are significantly higher than for coal-fired generation. The federal permitting process requires a longer lead time than coal-fired generation.

Any legislation that puts coal at a comparative disadvantage to other sources of fuel to generate electricity would have a serious negative effect on not only the coal industry, but on Kentucky's economic development potential and the citizens and businesses that depend on affordable electricity. As coal is and will continue to be the least-cost fuel for electricity generation, any legislation that adds costs to coal-fired electricity generation that are not also levied against other forms of generation would raise Kentucky's rates disproportionately compared with states having other resources and would thus lessen the differential in cost of electricity that Kentucky currently enjoys with respect to other states.

With Kentucky's long-standing reliance on coal for electricity generation and the resulting relative low electricity rates, there is tremendous potential for the state to benefit from increased emphasis on energy efficiency. Although our electric rates have been among the lowest in the nation, our citizens, businesses, and industries pay higher bills than many states with higher rates.

The subsurface geology of Kentucky is generally favorable for carbon sequestration and CO_2 enhanced oil and gas recovery. The Appalachian Basin in the east and the Illinois Basin in the west contain oil and natural gas fields, and deep saline aquifers for which available data indicates suitability for injection of CO_2. Many of the deeper formations in particular will require additional well data in key areas to fully evaluate their capacity for CO_2 injection and storage. Most of these porous and permeable formations are overlain by thick impermeable shale formations, which provide good seals to contain CO_2. Development of the ability to use this abundance of potential storage capacity may be critical to the viability of future coal-fired power plants (and hence, the viability of the Kentucky coal industry and maintaining favorable electricity rates in Kentucky). However, despite the thickness of sedimentary rocks and abundance of oil and gas fields in Kentucky, there are several concerns that will have to be addressed in some areas before sequestration can be implemented.

11. Assessment of long-term risks and uncertainties associated with carbon-management options

In addition to actual physical injection of CO_2, considerable modeling of injection is getting started. Questions which may be addressed by modeling and/or physical injection include:

- What happens to the CO_2 when it is injected? What are the physico-chemical and the chemical processes involved?
- How long can CO_2 remain sequestered underground?

- How much and where can CO_2 be stored in the subsurface locally, regionally, and globally?
- Are there sufficient opportunities for CO_2 -enhanced oil and gas recovery?
- How can a suitable storage site be identified and what are its geologic characteristics?
- What are the methods that we can use to monitor geologically stored CO_2?
- Will a geologic CO_2 storage site leak and how much leakage is acceptable?
- Can a geologic CO_2 storage site be operated safely, and if so, how and for how long?
- Can a CO_2 storage site be remediated if something goes wrong?

Large scale CO_2 management has never been implemented. Consequently, there are a number of unknowns, with attendant risk, at this stage of planning. These unknowns include:

- What are the legal and regulatory issues pertaining to geologic sequestration?
- Who will own, and be liable for, post-injection subsurface carbon dioxide?
- Who owns the subsurface pore space (storage space for carbon dioxide)?
- What are the likely costs of geologic sequestration and can we afford it?
- What government agency will be responsible for regulation of CO_2 sequestration?
- Who will be responsible for long-term monitoring, measurement, and verification of injected CO_2?
- What collateral environmental impacts may be caused by large scale deployment of possible solutions (for instance, from ocean injection)?
- The financial impact due to the unequal effect that carbon management will have on the relative costs of different electric generating options and different industries.
- The pace of development of any of the alternative technologies.

The single greatest long-term risk associated with CO_2 management is the unquantifiable liabilities related to the transportation, injection and storage of enormous quantities of CO_2 in geologic formations. Damage to property, human health, and the environment could occur from accidents, leaks, failure of storage systems and other circumstances where CO_2 might be released into the subsurface, surface or ambient air. A legal and regulatory framework governing CCS needs to be developed that includes specific mechanisms to address or cap these liabilities.

12. Identification of existing collaborative efforts and partnerships developed to address carbon dioxide issues in which Kentucky participates

In addition to the previously mentioned regional carbon sequestration projects, there are a number of collaborative efforts underway in Kentucky. Working closely with utility companies in Kentucky [E-ON US, East Kentucky Power Cooperative (EKPC), Kentucky Power (AEP), Duke Energy and TVA], the University of Kentucky's Center for Applied Energy Research is in the early stages of forming a research alliance called the "Kentucky Consortium for Advanced Power Generation". The purpose of this consortium is to maintain and strengthen Kentucky's comparative advantage as a low-cost producer of electricity, while simultaneously improving the quality of Kentucky's environment, in anticipation of federal limitations on carbon dioxide CO_2. The Governor's Office of Energy Policy has provided funding for the organizational phase of this consortium.

The consortium will build on the successes the CAER is showing with the 0.1MW pilot plant that has been built for post-combustion CO_2 capture. These successes, coupled with financial support from the utilities in Kentucky, have led the CAER to propose a series of slip-stream field investigations at selected utility's plants using a portable 1MW slip-stream post-combustion apparatus. The test sites will be selected based upon system configurations and coal types at the various power plants. This study conducted at a power plant represents a critical step in developing and demonstrating practical technologies for reducing CO_2 emissions from Kentucky's existing fleet of coal-fired power plants. The study will also help train Kentucky's workforce to respond to challenges that will be faced in a carbon-constrained world.

The Kentucky Public Service Commission, as a member of the National Association of Regulatory Utility Commissioners (NARUC), is actively engaged in several committees and workgroups. In July 2007, NARUCs' Board of Directors passed a resolution urging Congress to protect ratepayers and existing state regulatory authority as it considers potential climate-change legislation. Chairman Mark David Goss of the Kentucky Public Service Commission serves as a member of the board of directors of NARUC. PSC Chairman Mark David Goss serves as chairman of NARUC's Clean Coal Technology and Carbon Capture and Storage Subcommittee. The Subcommittee serves three functions: (1) Educate NARUC members about clean coal technologies and carbon capture and storage issues; (2) Identify the barriers and opportunities regarding these technologies; and (3) Serve as a resource for stakeholders to communicate with the various state utility regulators.

Working with NARUC staff, the Subcommittee recently obtained funding from the U.S. Environmental Protection Agency to develop an analysis of regulatory treatment of emission allowances by the states, a primer focusing on advanced coal-fired generation technologies, and a report on prioritizing regulatory issues on carbon capture and storage for state commissioners.

Chairman Goss is also a member of NARUC's Advanced Coal Technology Workgroup. The workgroup has recommended development of risk characterization, risk management, and liability mechanisms to enable the accelerated deployment of carbon capture and storage technologies.

Another collaborative project involves the Kentucky Division of Forestry, which established Kentucky's first tree planting project for carbon sequestration in 2004. A partnership was established with AEP in which the Kentucky Division of Forestry was awarded $96,000 to reforest 400 acres on Green River State Forest. Nearly 174,500 hardwood tree seedlings were planted on the Green River State Forest at the confluence of the Green River and Ohio River in Henderson County. AEP, as part of the U.S.

Department of Energy's Global Climate Challenge Program (GCCP), can offset its carbon emissions by planting forests that will absorb and store carbon. A healthy, vigorously growing forest absorbs more carbon. The Division of Forestry, in managing the state forest as a premier forest stewardship demonstration area, inherently strives for healthy fast growing trees.

Recently the Mountain Association for Community and Economic Development (MACED) began accepting applications for a carbon credits program. Enrollment is open to private forest landowners in the Appalachian region of Kentucky. Second year enrollment will begin in early 2008 and enrollment statewide will be considered. Forest landowners owning 40 acres or more are encouraged to apply. Four requirements must be met in order to be eligible for carbon credit payments. Based on the June 2007 Chicago Climate Exchange (CCX) market price, a forest landowner could expect to receive $4.00 – $5.00 per acre per year dependent on the average age of the trees and the overall condition of the property.

13. Identification of the types of incentives or other government assistance necessary to support the development and implementation of new technologies to capture and sequester carbon.

Prior to a cap and trade system or carbon tax making sequestration of CO_2 economical, a sequestration tax credit should be provided at a level equal to the cost of compressing, transporting, and storing CO_2. This would function similarly to a production tax credit for renewable fuels. It would most likely be utilized by industries already separating CO_2 from their production stream. This would provide a source of CO_2 for large scale studies of carbon capture and storage (CCS) prior to enactment of economy wide requirements to cut carbon emissions. The NARUC Advanced Coal Technology Work Group recommends that any GHG policy should include provisions that result in the early and widespread development and deployment of advanced coal technologies.

Any national mandatory policy driver should include provisions that will enable:

- the early deployment of advanced carbon control technologies, particularly CCS;
- a rapid reduction in the cost of CCS systems; and
- a rapid reduction in the energy penalty of carbon capture systems.

Policymakers should judge any broad-based GHG policy by its ability to bring about such developments.

In order to achieve these goals it will be necessary to provide incentives for the deployment of CCS systems. Such incentives could form part of the mandatory policy driver or be pursued through *supplementary policies* that complement broader national GHG policies through increased attention to and incentives for specific key technologies.

A two-pronged approached is necessary to bring about the widespread, accelerated deployment of advanced carbon control technologies, particularly CCS:

1) A national, mandatory policy that limits GHG emissions (the “stick”). Without such a national policy CCS will not be developed and deployed at the speed and scale necessary to enable coal to continue its role in meeting the nation’s electricity needs while stabilizing the concentration of CO_2 in the atmosphere at acceptable levels. However, to enable the required rapid development and deployment of CCS technologies:
2) Either as part of the mandatory policy or in the form of supplementary policies, incentives will be needed due to the high current costs and energy penalties of these technologies (the “carrot”). For example, supplemental policies may be needed to correct a policy’s inability to ensure sufficient early funding for deployment and needed RD&D.

Incentives Necessary for Sequestration

- Determination of post-injection ownership and liability for subsurface carbon dioxide
- Tax incentives for use of man-made CO_2 in enhanced oil recovery projects
- Permitting and regulatory streamlining
- Resolve ownership issues for subsurface pore space (storage space for CO_2)
- Determine agency responsible for regulation of geologic CO_2 sequestration
- Assign responsibility for long-term monitoring, measurement, and verification of injected CO_2